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(71) Applicant(s)
WesternGeco Limited
(Incorporated in the United Kingdom)
Schlumberger House, Buckingham Gate, Gatwick Airport, GATWICK, West Sussex, RH6 0NZ, United Kingdom

(72) Inventor(s)
Stephen Horne
Richard Bale
Philippe Caprioli

(74) Agent and/or Address for Service
Marks & Clerk
4220 Nash Court, Oxford Business Park South, OXFORD, OX4 2RU, United Kingdom

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(54) Abstract Title
Method and apparatus for determining receiver orientation and/or vector infidelity in multi-component seismic data

(57) Seismic data is processed to determine the slowness vector and components of the polarisation vector along first and second non co-linear directions. These are then used to obtain information about the orientation and/or vector infidelity of the seismic data receiver. In a second embodiment this information is obtained by calculating and comparing an expected polarisation vector to the observed polarisation vector. The system is designed for use with seismic acquisition equipment where the receivers are either autonomous or decoupled from their cable so that their positions cannot be defined by the position of the survey cable.

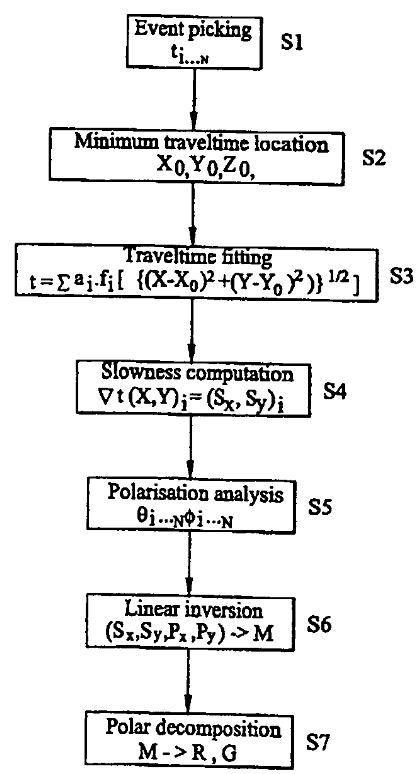

FIG 1

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At least one drawing originally filed was informal and the print reproduced here is taken from a later filed formal copy.

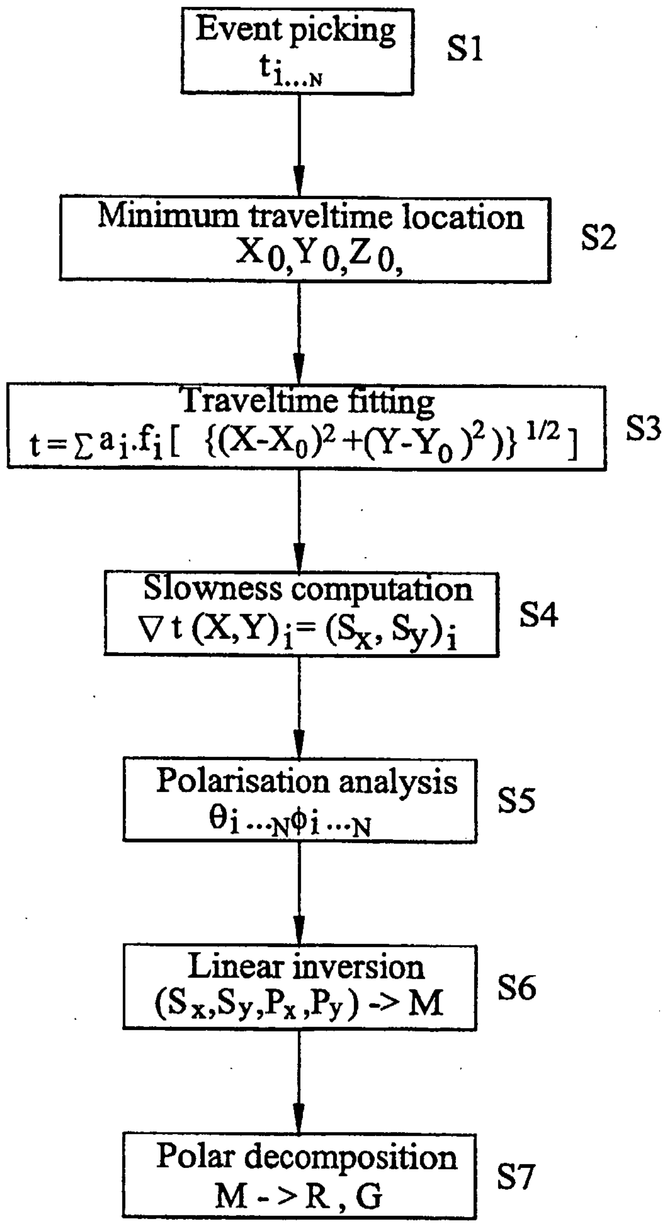
Event picking
$t_{i \ldots N}$
S1
Minimum traveltime location
$X_0, Y_0, Z_0,$
S2
Traveltime fitting
$t = \sum a_i . f_i [\ \{(X-X_0)^2 + (Y-Y_0)^2)\}^{1/2}]$
S3
Slowness computation
$\nabla t\,(X,Y)_i = (S_x, S_y)_i$
S4
Polarisation analysis
$\theta_{i \ldots N} \phi_{i \ldots N}$
S5
Linear inversion
$(S_x, S_y, P_x, P_y) \rightarrow M$
S6
Polar decomposition
$M \rightarrow R\,,\, G$
S7

FIG 1

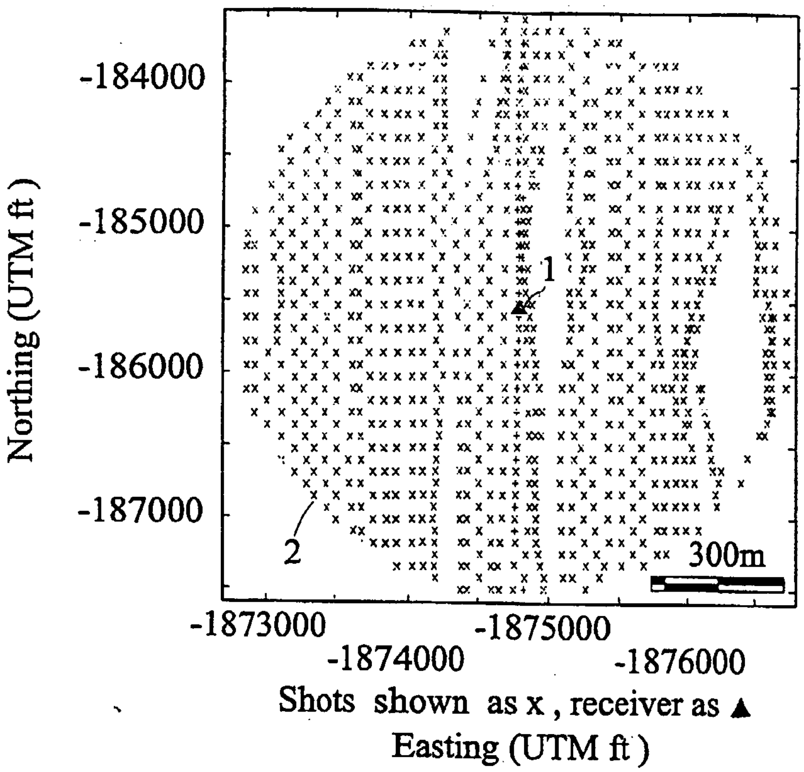
-184000
-185000
-186000
-187000
Northing (UTM ft)
1
2
300m
-1873000
-1874000
-1875000
-1876000
Shots shown as x , receiver as ▲
Easting (UTM ft)

FIG 2

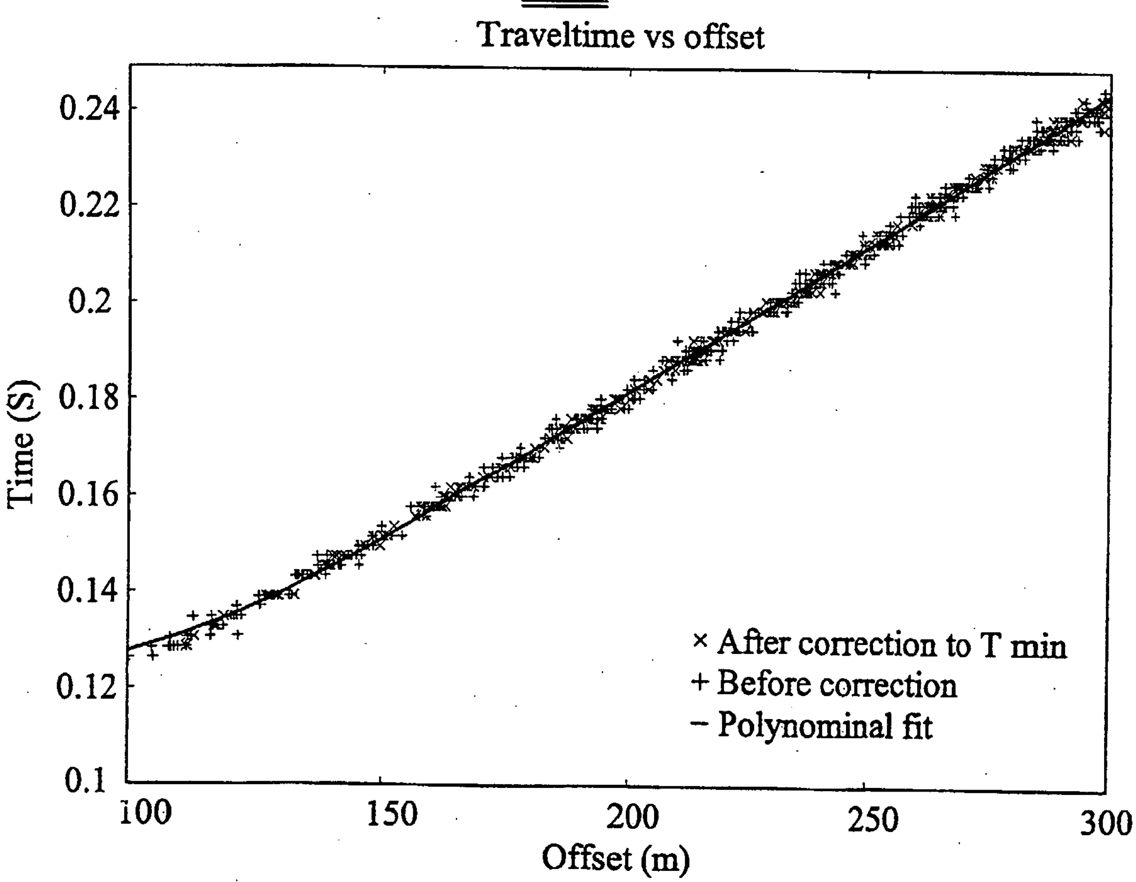
Traveltime vs offset
0.24
0.22
0.2
0.18
0.16
0.14
0.12
0.1
Time (S)
100
150
200
250
300
Offset (m)
× After correction to T min
+ Before correction
− Polynominal fit

FIG 3

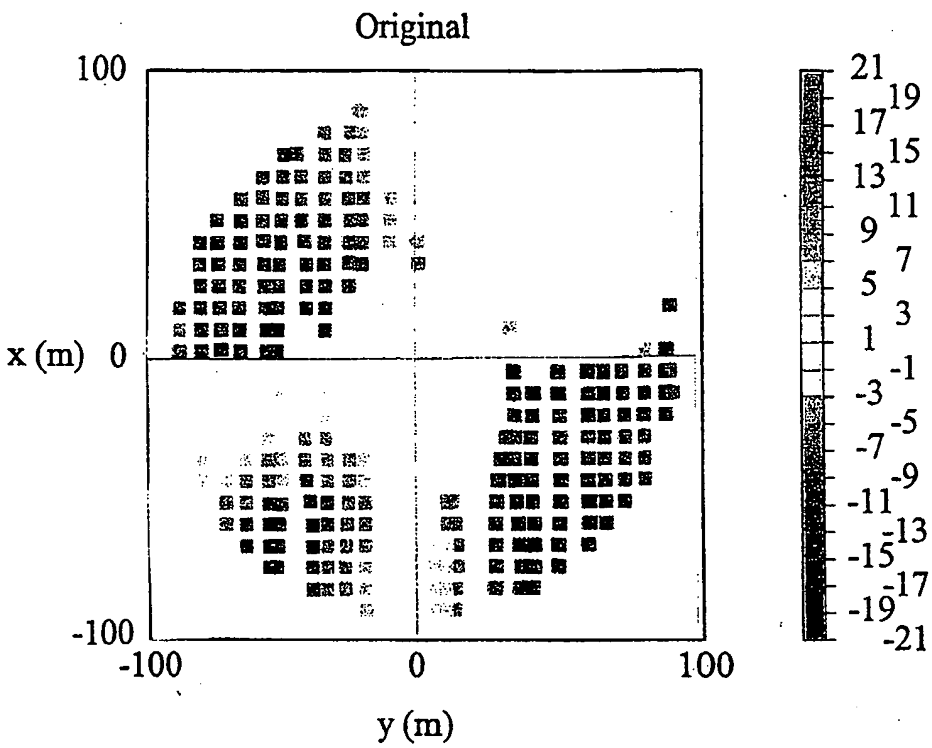
Original
100
x (m)
0
-100
-100
0
100
y (m)
21
19
17
15
13
11
9
7
5
3
1
-1
-3
-5
-7
-9
-11
-13
-15
-17
-19
-21

FIG 4[a]

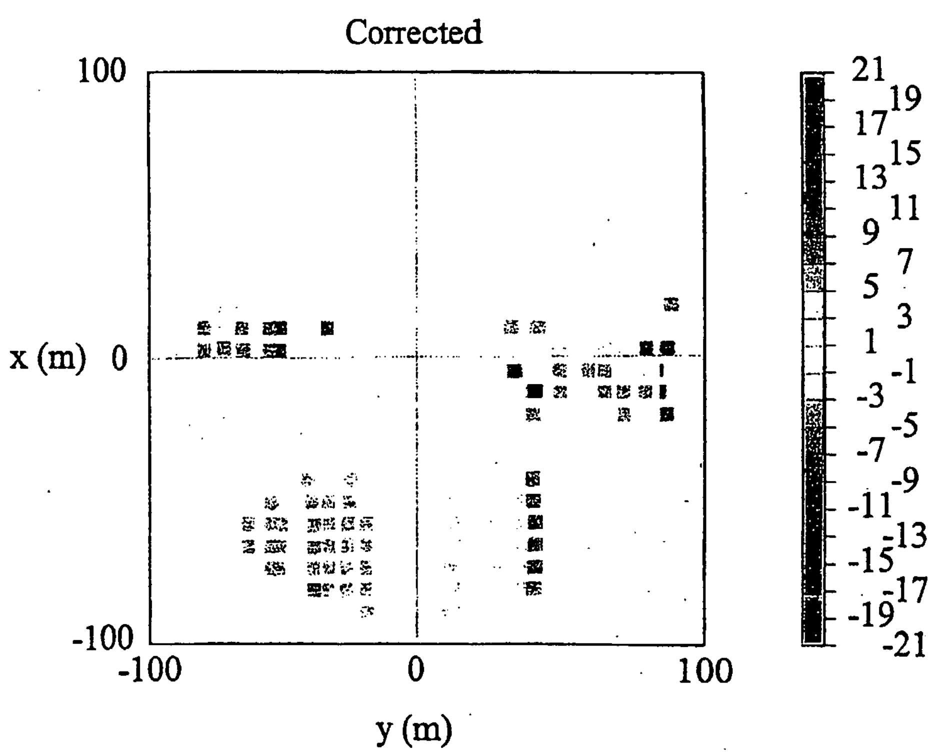
Corrected
100
x (m)
0
-100
-100
0
100
y (m)
21
19
17
15
13
11
9
7
5
3
1
-1
-3
-5
-7
-9
-11
-13
-15
-17
-19
-21

FIG 4[b]

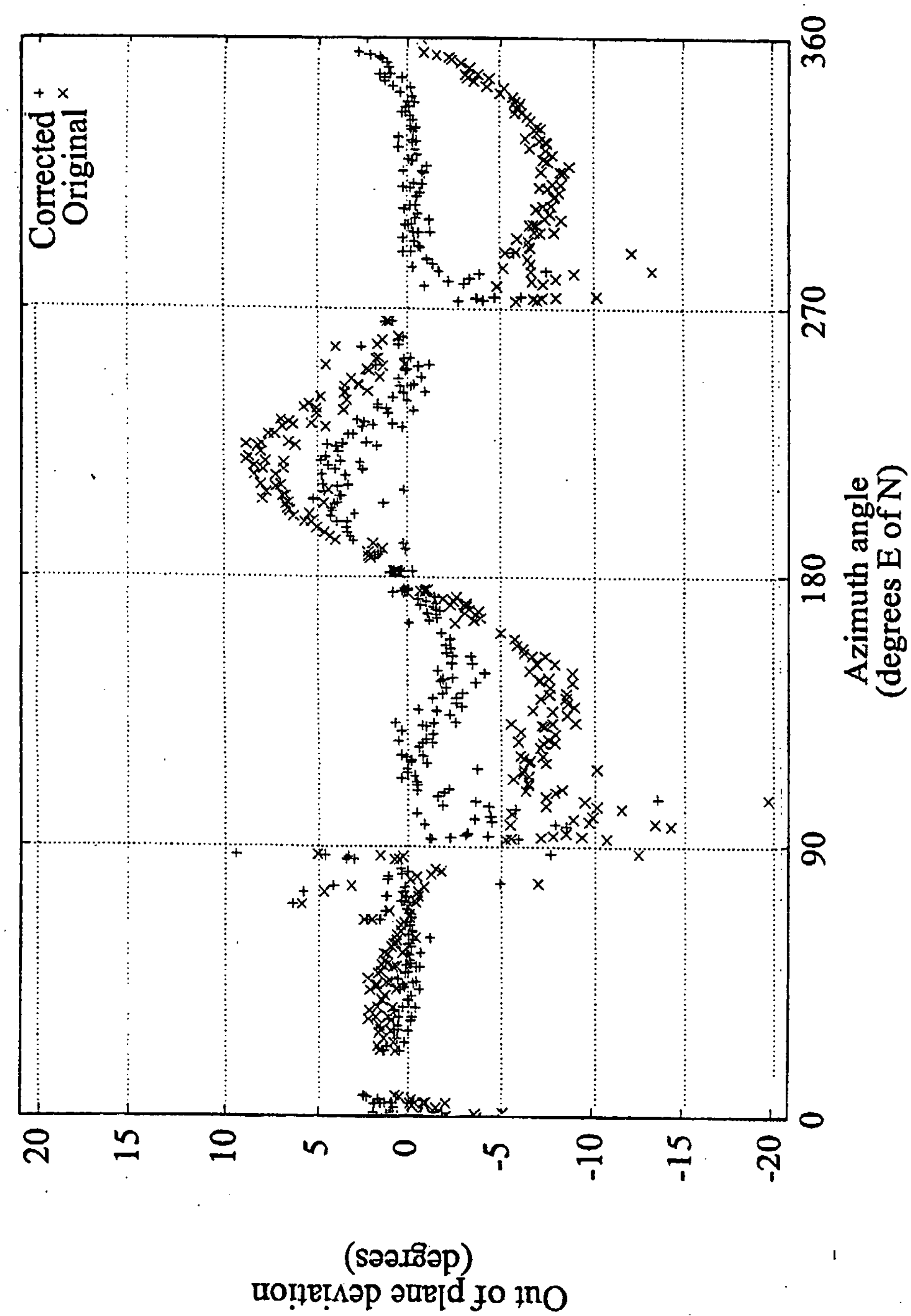
Corrected +
Original ×
20
15
10
5
0
-5
-10
-15
-20
Out of plane deviation
(degrees)
0
90
180
270
360
Azimuth angle
(degrees E of N)

FIG 5

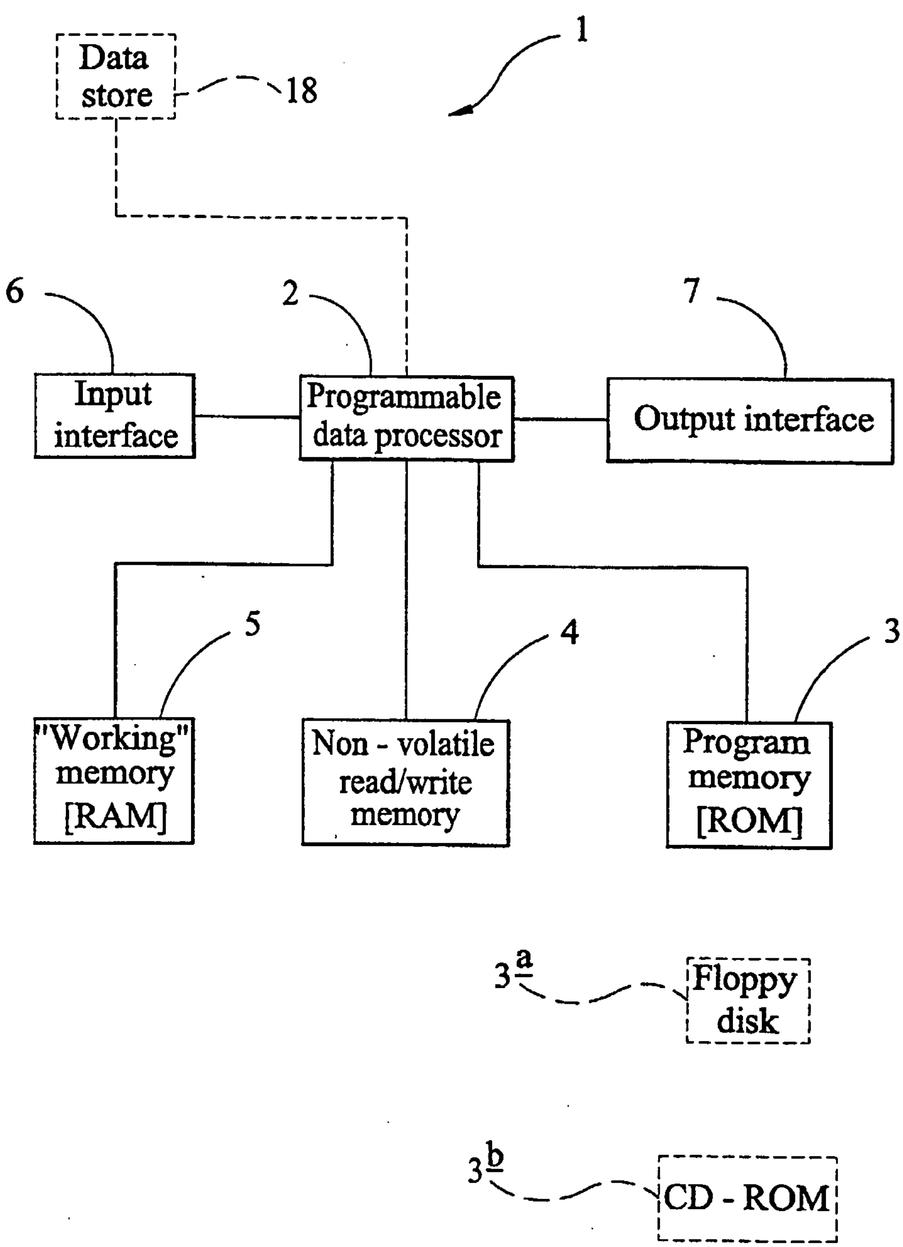
1
Data store
18
6
2
7
Input interface
Programmable data processor
Output interface
5
4
3
"Working" memory [RAM]
Non - volatile read/write memory
Program memory [ROM]
3a
Floppy disk
3b
CD - ROM

FIG 6

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A method of, and an apparatus for, processing seismic data

The present invention relates to a method of processing seismic data acquired at a receiver to obtain information about the orientation of the receiver and/or information about the vector infidelity of the receiver. The invention can be applied to, for example, a receiver disposed on the earth's surface, or to a receiver disposed within a borehole (including a receiver disposed within the annular region behind a borehole casing or within a "rat" hole drilled from the main borehole). The term "earth's surface" as used herein includes the sea-bed, land, and the transition zone. The present invention also relates to an apparatus for processing seismic data, and to a storage medium containing a program for a data processor of an apparatus.

A seismic receiver generally comprises one or more seismic sensing elements disposed within a housing. Examples of seismic sensing elements are a geophone, which measures the component of the elastic wavefield along the axis of the geophone, and a hydrophone, which measures pressure.

When the receiver is deployed in a desired survey location by being disposed on the earth's surface, the coupling of the seismic sensing element(s) to the earth is provided by the housing of the receiver; the housing also provides physical protection for the sensing element(s). Receivers of this general type are generally used by attaching the receiver housings to a support cable at intervals along the length of the cable. The support cable is provided with means such as electrical leads or optical connectors that enable output signals from the receivers to be transmitted to monitoring and/or recording equipment, and to enable power to be provided to the receivers. For a land-based survey, the cable is disposed on the land so that the receivers are located at their desired positions. In the case of sea-bed seismic data acquisition, the cable is lowered onto the sea-bed to deploy the receivers at their desired locations on the sea-bed. Alternatively, in the case of a towed marine receiver array, the cable is suspended at a desired depth below the water surface and is towed through the water, for example by a survey vessel. As a further alternative, the cable may be deployed within a borehole to provide a VSP (vertical seismic profile) receiver array. Receivers may also be deployed

without being attached to a cable. For instance, autonomous sensors can record and store data locally, for example on a hard disk, for later retrieval, or can transmit data, for instance via radio, to another location for recordal there.

A seismic receiver provided with two or more seismic sensing elements is able to measure two or more parameters of the received seismic energy, and is thus known as a multi-component seismic receiver. One application of multi-component seismic receivers is as sea-bed seismic receivers - that is, as receivers intended to be disposed on the sea-bed. Sea-bed seismic receivers generally record the pressure and the elastic wavefield of the seismic energy incident on the receiver. The pressure is a scalar quantity, whereas the elastic wavefield is a vector quantity and it is therefore necessary to measure the components of the elastic wavefield in three non-coplanar directions. This is done by providing the receiver with at least three geophones, having their axes arranged in three non-coplanar directions so that the receiver can measure the components of the wavefield in the three non-coplanar directions. The three directions chosen are usually the x-direction, the y-direction, and the z-direction (vertical). In total, therefore, the receiver can measure four components of the seismic data (the pressure and three components of the elastic wavefield), and the receiver is known as a 4-C (four-component) receiver.

A multi-component receiver intended for use on land would typically not contain a hydrophone, but would contain three geophones, oriented so that their axes are mutually orthogonal. Such a receiver measures three components of the seismic data (three components of the elastic wavefield), and the receiver is known as a 3-C (three-component) receiver.

Four-component seismic data recording at the sea-bed has proven to be a very successful method for imaging through gas saturated overburdens and for characterising hydrocarbon reservoirs through lithology identification and fluid discrimination. The multi-component data describing the elastic wavefield are especially useful, since they enable the separation of the compressional P-waves from the shear S-waves.

In a conventional seabed acquisition system the receivers are firmly coupled to the cable, so that the orientation of each receiver, relative to the cable, is known. Usually, each receiver is aligned on the cable so that one sensing element records the component of the elastic wavefield along the cable (this is also known as the in-line direction, and is generally taken to be the x-direction), and another records the component of the wavefield transverse to the cable (this is also known as the cross-line direction, and is generally taken to be the y-direction). The third sensing element records the vertical component of the wavefield.

In a conventional receiver array, the orientation of each receiver on the cable is defined when the receiver is attached to the cable, so that the receiver heading is defined before the cable is deployed. (The "heading" of a receiver is its orientation in a horizontal plane.) Thus, the heading of each receiver can in principle be determined from its position on the cable. However, twisting and coiling of the support cable may occur as the cable is deployed, and this would mean that actual heading of a receiver may be different from the theoretical heading determined from the receiver's position on the cable. Moreover, the actual position of a receiver deployed on the sea-bed may also be different from its theoretical position determined from the receiver's position on the cable.

Furthermore, new seabed acquisition systems are being designed in which the receivers are decoupled from the cable. In these new acquisition systems, although each receiver will still measure the components of the wavefield along its internal x- and y-axes, knowledge of the receiver's position on the cable will not be sufficient to determine the orientation of the receiver's x- and y- axes. Thus, determining the receiver's heading solely from its position on the cable may well be inaccurate, with a possibly severe effect on the quality of the results of processing the data.

Determining the receiver heading solely from the receiver's position is not possible in the case of an autonomous receiver.

A further problem that occurs in processing data acquired by a multi-component seismic sensor is that of vector infidelity. By "vector infidelity" it is meant that one or more components of the recorded wavefield is/are distorted compared to the true particle motion. Sub-optimal design of the sensor housing or of the cable can cause such distortions, which tend to be particularly severe for specific components of the recorded data. In particular, infidelity between the in-line (x-direction) and cross-line (y-direction) components of the elastic wavefield can be a serious problem.

Various techniques for correcting for vector infidelity have been proposed. For example, J.E. Gaiser, in "Compensating OBC data for variations in geophone coupling", 68th Ann. Internat. Mtg, Soc. Expl. Geophys. pp1429-1432 (1998), and C. Bagaini et al, in "Assessment and calibration of horizontal geophone fidelity in seabed-4C using shear waves", 62nd EAGE Conference Glasgow, Extended Abstracts, paper L02 (2000), have proposed techniques for calibrating the recordings of different components of the wavefield in order to correct for vector infidelity. These techniques rely upon the minimisation of transverse energy, assuming all energy to travel in the radial-vertical plane. Both schemes, however, define the radial direction as the direction from source to receiver, which implicitly assumes that the earth is laterally invariant. This assumption means that any subsurface structures present will cause systematic uncertainties in the calibration filters, as pointed out by Gaiser (supra).

The errors in the calibration filters have hitherto been minimised statistically, but this can be done only if the acquired data has a good azimuth coverage. The present invention, however, makes it possible to perform a correct receiver calibration without the assumption of a 1-D earth model, for any number of shots with an appropriate azimuth coverage.

A first aspect of the present invention provides a method of processing multi-component seismic data acquired at a receiver, the method comprising the steps of:

a) determining the components of the slowness vector of the acquired seismic data along first and second horizontal directions, the first and second directions not being co-linear;

b) determining the components of the polarisation vector of the acquired seismic data along the first and second horizontal directions; and

c) obtaining information about the orientation of the receiver and/or information about the vector infidelity of the receiver from the horizontal components of the slowness vector and the horizontal components of the polarisation vector.

In a preferred embodiment, step (c) comprises determining a transfer operator from the horizontal components of the slowness vector and the horizontal components of the polarisation vector.

The transfer operator may provide information as to whether the receiver is correctly oriented (that is, whether the internal x- and y-axes of the receiver are oriented along the global x- and y-axes used in the seismic survey). Additionally, or alternatively, the transfer operator may also provide information about the presence in the seismic data of effects due to vector infidelity. Once the transfer operator has been determined, it can be used to correct the acquired seismic data for the effects of mis-orientation of the receiver and/or vector infidelity.

A second aspect of the present invention provides a method of processing multi-component seismic data acquired at a seismic receiver, the method comprising the steps of:

a) calculating the expected polarisation vector of seismic data acquired at the receiver;

b) determining the observed polarisation vector of seismic data acquired at the receiver; and

c) obtaining information about the orientation of the receiver and/or information about the vector infidelity of the receiver from the expected polarisation vector and the observed polarisation vector.

In a preferred embodiment, step (c) comprises determining a transfer operator from the expected polarisation vector and the observed polarisation vector.

This aspect is similar in concept to the first aspect of the invention. It may be applied in cases where the expected polarisation of the seismic data is known, or can be reliably calculated from first principles (for example if seismic properties of the survey site are known).

The transfer operator may be a frequency-dependent transfer operator.

A third aspect of the invention provides an apparatus for processing multi-component seismic data acquired at a receiver, the apparatus comprising:

a) means for determining the components of the slowness vector of the acquired seismic data along first and second horizontal directions, the first and second directions not being co-linear;

b) means for determining the components of the polarisation vector of the acquired seismic data along the first and second horizontal directions; and

c) means obtaining information about the orientation of the receiver and/or information about the vector infidelity of the receiver from the horizontal components of the slowness vector and the horizontal components of the polarisation vector.

A fourth aspect of the present invention provides an apparatus for processing multi-component seismic data acquired at a seismic receiver, the method comprising the steps of:

a) means for calculating the expected polarisation vector of seismic data acquired at the receiver;

b) means for determining the observed polarisation vector of seismic data acquired at the receiver; and

c) means obtaining information about the orientation of the receiver and/or information about the vector infidelity of the receiver from the expected polarisation vector and the observed polarisation vector.

The apparatus may comprise a programmable data processor.

A fifth aspect of the present invention provides a storage medium containing a program for a data processor of an apparatus as defined above.

Preferred embodiments of the present invention will now be described by way of illustrative example with reference to the accompanying figures in which:

Figure 1 is a block flow diagram showing the principal steps of a method according to an embodiment of the present invention;

Figure 2 is a schematic plan view of a seismic surveying arrangement for acquiring seismic data to which a method of the present invention can be applied;

Figure 3 illustrates the effect of the present invention on the relationship between offset and travel time;

Figures 4(a) and 4(b) illustrate the effect of the present invention on the polarisation difference in the horizontal plane;

Figure 5 illustrates the effect of the present invention on the polarisation difference as a function of azimuth; and

Figure 6 is a block diagram of an apparatus according to the present invention.

In a laterally homogenous and azimuthally isotropic medium, the projection of the slowness vector of acquired seismic energy onto a horizontal plane is simply related to the horizontal projection of the polarisation vector of the seismic energy. The horizontal projection of the slowness vector should be parallel to the horizontal projection of the polarisation vector for a p-wave or for a s_v-wave, and should be perpendicular for a s_h-wave. The present invention uses this to obtain a transfer operator that relates the slowness vector and the polarisation vector obtained from acquired seismic energy. The transfer operator provides information about the

orientation of the geophone and the vector infidelity, and this can be used to correct the acquired seismic data.

Figure 1 illustrates the principal steps in a method of the present invention. The invention will be described with reference to common receiver gather seismic data, in which data is acquired at a receiver for seismic energy emitted at two or more seismic sources. One example of a common receiver seismic surveying arrangement is shown schematically in Figure 2. This seismic surveying arrangement contains a single receiver 1, indicated by a triangle, and a plurality of seismic sources 2, each indicated by an "x" or a "+". In a survey, each of the seismic sources will be actuated in sequence, and data will be acquired at the receiver. Each actuation of a seismic source is known as a "shot". The seismic data acquired at the receiver data will thus, in principle, consist of a series of sets of traces of the seismic energy acquired at the receiver. For example, in the case of a 3-C receiver, each shot will generate a set of three traces, one trace for each orthogonal component of the elastic wavefield measured by the receiver. In the case of a 4-C receiver, each shot will additionally generate a further trace of the pressure measured by the receiver.

The first step, S1, of the present invention is to pick a common seismic event in each trace of the seismic data. In a preferred embodiment the first break event is identified in each seismic trace, but other events may also prove suitable. (The "first break" event is the first arrival of seismic energy at the receiver.) This step is preferably carried out automatically, but may be carried out manually.

If desired, step S1 may be preceded or followed by a preliminary analysis step (not shown in Figure 1) in which unsuitable traces are identified and eliminated from further analysis.

Step S1 will provide, for the selected event, the travel time of seismic energy from each seismic source to the receiver. Thus, the results of step S1 will essentially be a set of values of travel time of seismic energy for the selected event against source position. More formally, the results are sets of values (t_i, x_i, y_i), for $1 \leq i \leq N$ where N is the total

number of shots. In this, t_i is the travel time of seismic energy in the i^{th} shot for the selected event, and x_i, y_i are the x- and y-co-ordinates of the source used to generate the i^{th} shot (which is the i^{th} source if the data does not contain multiple shots for any source). These travel times represent discrete samples of a two-dimensional travel time surface that represents the travel time of seismic energy to the receiver as a function of the position of the source. In general, the travel time will increase as the distance between the source and the receiver increases, and this implies that the travel time surface has a minimum. Provided that the geometry of the seismic survey is suitable it is possible to estimate the spatial position of the minimum in the travel time surface.

The minimum in the travel time surface may be determined in any suitable way, for example by fitting a surface or a series of curves to the discrete travel time values produced in step S1. Alternatively the minimum in the travel time surface may be determined by linearising the traveltime equation and inverting to obtain the co-ordinates of the minimum.

The seismic surveying arrangement used to acquire the seismic data to which this method of the invention is applied must produce seismic data from which the minimum travel time position can be reliably estimated. One suitable seismic surveying arrangement is a "cross-spread" seismic surveying arrangement in which a shot line is arranged orthogonal to a receiver line.

At the minimum travel time position the spatial derivatives of the travel time surface are zero and this implies that, at this location, the seismic energy is travelling vertically. This implies that the receiver lies directly below this minimum travel time position – that is, that the true x- and y-co-ordinates of the receiver are x_0 and y_0, where the minimum travel time position occurs at (x_0, y_0). Further details of this technique are given by S. A. Horne et al, in "Fractured Reservoir Characterisation using Multi-Azimuthal Walk Away VSPs", 68th Annual International Meeting of Society of Exploration Geo-Physicist, Expanded Abstracts pp1640-1643 (1998) in the context of correcting vertical seismic profile (VSP) seismic data for uncertainties in the receiver location.

This step essentially determines the actual position of the receiver, as opposed to the intended position where the receiver should have been deployed. The depth of the receiver, z_0, may also be determined in this step.

The receiver position determined in step S2 may be used in subsequent data processing steps, to improve the accuracy of the results, in addition to correcting the data for receiver mis-orientation and vector infidelity as described below.

At step S3 the travel times of the picked event are plotted relative to the actual receiver location as determined by the location of the minimum travel time. The offset (horizontal distance between the source and the receiver) is determined for each source, using the corrected receiver position as determined by the minimum travel time position. The corrected offset for the i^{th} shot is therefore given by

$$\text{offset}_{corr} = ((x_i - x_0)^2 + (y_i - y_0)^2)^{1/2} \qquad (1)$$

where the x- and y- co-ordinates of the source used to generate the i^{th} shot are x_i and y_i respectively.

When the travel times of the picked event are plotted relative to the minimum travel time location they should be independent of azimuth if the medium is azimuthally isotropic. Thus, plotting the travel time against the corrected offset (that is, the offset relative to the minimum travel time position) should yield a single curve.

Step S3 further comprises fitting a curve to the results obtained by plotting the travel time against the corrected offset. The curve may be, for example, a polynomial fit to the plot of the travel time against the corrected offset. In the fitting equation shown in set S3, "f_i" denotes basis functions used in the fitting process and "a_i" denotes fitting coefficients.

The radial component of the slowness may be obtained for every shot in the gather by locally differentiating the curve of the travel time against corrected offset. Thus, at step S4 the fitted curve obtained in S3 is locally differentiated with respect to the corrected offset to obtain the radial component of the slowness for every shot in the gather. Two orthogonal horizontal components (preferably the x- and y-components) of the slowness for each shot are obtained from the radial component of the slowness, by projecting the radial slowness obtained for the shot relative to the azimuth measured from the minimum travel time position to the respective source.

At step S5 two orthogonal horizontal components (preferably the x- and y-components) of the polarisation vector are estimated for the seismic data. Methods for estimating the polarisation vector from multi-component seismic data are known, and any suitable method can be used. One suitable method is that proposed by E.R. Kanasewich in "Time Sequence Analysis in Geophysics" (Third Edition), University of Alberta Press (1981). This process is preferably repeated for each shot of the gather, to obtain an estimate of the horizontal components of the polarisation vector for each shot.

As noted above, the polarisation and slowness are related, and this relation may be expressed as a sequence of linear operations:

$$s = \mathbf{R}\mathbf{G}\,p \qquad (2)$$

where s is a normalised slowness vector, p is a normalised polarisation vector, and **R** and **G** are respectively rotation and gain operators. The vectors s and p are in the x-y plane. The rotation and gain operators may conveniently be represented as matrices. The rotation operator **R** expresses the angle by which the horizontal components of the polarisation need to be rotated to be coincident with the horizontal components of the slowness vector. The gain operator expresses how the horizontal components of the polarisation need to be scaled, relative to one another, to have the same relative magnitudes as the horizontal components of the slowness vector.

The rotation and gain operators may be combined to give a single transfer operator represented by **M** = **RG**. Equation (2) may therefore be re-written as:

$$s = \mathbf{M}\,p \tag{3}$$

Equation (3) expresses that the result of operating on the polarisation vector, with the transfer operator **M**, is the slowness vector. Equation (3) can be re-written in a form that is more suitable to linear inversion as:

$$s = \mathbf{P}\,m \tag{4}$$

where P is a partitioned matrix that contains the polarisations and *m* is a vector that describes the elements of the transfer matrix **M**.

This equation is solved at step S6 to obtain an estimate of the transfer matrix **M**. Step S6 may also provide estimates of the errors that are associated with the elements of the estimated transfer matrix. This process is preferably repeated for each shot.

Finally, at step 7 the estimated transfer matrix **M** derived from the linear inversion in step S6 is decomposed to give a rotation matrix **R** representing a rotation operator and a gain matrix **G** representing a gain operator. This decomposition step may be carried out using any suitable technique, for example the technique of "polar decomposition" which is widely used in other disciplines such as computer animation. Details of a suitable polar decomposition technique are given by K. Shoemake and T. Duff in "Matrix Animation and Polar Decomposition" proceedings of Graphic Interfaces (1992).

The transfer operator may now be used to correct the seismic data for the effects of sensor mis-orientation and vector infidelity. The transfer operator can be applied to each trace of the common receiver gather, over the entire trace length, for all traces in the gather.

Preferably a transfer operator is calculated for each shot, from the polarisation and slowness vectors determined for that shot, and the transfer operators are then averaged over all shots. The resultant averaged transfer operator may then be used to correct all data subsequently acquired at that receiver (although in principle the transfer matrix could be re-computed each time that data was acquired at the receiver).

In the flow chart shown in Figure 1 the slowness vector is computed first, and the polarisation vector is computed subsequently. It is not essential for the slowness and polarisation to be computed in this order. It would be possible for the polarisation to be computed before the slowness vector is computed, or for the computation of the slowness to be carried out in parallel with the computation of the polarisation.

In the embodiment of Figure 1 the slowness vector is derived from the acquired data by locally differentiating the curve of the travel time against corrected offset. The invention is not limited to this method of obtaining the slowness, and the slowness may be obtained in any suitable way. As one example, the slowness may be obtained using shot triangles, as described in co-pending UK patent application No 0106091.2.

In one example, the above method was applied to seismic data acquired in a survey carried out in the Teal South Field in the Gulf of Mexico. The seismic data were acquired using the seismic surveying arrangement shown in Figure 2. As noted above, this uses a single receiver disposed on the sea-bed and surrounded by a plurality of sources, so that the acquired data is a common receiver gather. The data consist of a set of traces, each obtained by actuating a particular one of the sources.

The selected seismic event in the traces was the first break, and this event was identified in each trace of the gather. This was done using an automatic picking method.

A polarisation analysis was applied to the data, over a fixed time window that included the first break event. The polarisation angles of the traces were estimated in this analysis to give the x- and y- components of the polarisation using the Kanasewich method.

Traces obtained from seismic sources having a very low offset were rejected, because clipping can occur in these traces if the signal exceeds the maximum recording range of an instrument. Traces obtained using sources having a long offset were also rejected, because interfering arrivals can occur in these traces and this makes picking the first break event unreliable.

After rejecting traces obtained from sources having a very low or very high offset, the remaining traces were then analysed to determine the minimum travel time position. This was done by linearising the direct travel time equation and inverting to obtain the receiver co-ordinates. It was found that the minimum travel time position was located at (-0.163, -3.314)m relative to the navigation co-ordinates. (The navigation co-ordinates are derived after the deployment of the cable to indicate where the receiver has been deployed.)

The offset of each of the traces used in the determination of the minimum travel time position was then re-calculated, to provide the offset between the source and the minimum travel time location. The effect of this step is shown in Figure 3, which illustrates the travel time of the first break event as a function of offset between the source and the receiver. Data points shown by a "+" indicate the travel time of the first break event plotted against the uncorrected offset – that is the offset between the source and the navigation co-ordinates. Data points plotted with a "x" show the travel time as a function of the corrected offset, that is, the offset between the source and the minimum travel time location (which is assumed to be the actual position of the receiver). The solid line in Figure 3 is a polynomial fit of the travel time to the corrected offset.

It will be noted that the corrected data points shown in Figure 3 have a significantly reduced scatter than do the uncorrected points. This indicates that the correction has been successful.

If it is assumed that the medium through which seismic energy propagates from the source to the receiver is homogenous and azimuthally isotropic, then the travel time is a function only of offset. This assumption is generally reasonable for the first break event in a marine seismic survey (except at very long offsets), since the first break seismic energy propagates from the source to the receiver through the water layer. It is therefore a reasonable assumption to calculate the polynomial fit between the travel time and the corrected offset.

The radial component of the slowness of the seismic data was then computed by differentiating the polynomial fit between the travel time and corrected offset, with respect to the corrected offset. The two horizontal components of the slowness for a particular source location were then computed from the radial component of the slowness, by projecting the radial component of the slowness into the two horizontal components based on the azimuthal angle measured from the minimum travel time location to the location of the source.

A linear inversion process was then applied to the estimated slowness and estimated polarisation, to obtain the transfer operator. In this example the transfer operator was a 2 x 2 matrix having the form,

$$M = \begin{pmatrix} 0.9258 & -0.0268 \\ 0.0456 & 1.094 \end{pmatrix}$$

Polar decomposition of the general transfer matrix yields the following rotation and gain operators:

$$R = \begin{pmatrix} 0.9994 & -0.0358 \\ 0.0358 & 0.9994 \end{pmatrix}$$

and

$$G\begin{pmatrix} 0.9262 & 0.0064 \\ 0.0064 & 1.095 \end{pmatrix}$$

As noted above, the polarisation vector is parallel to the slowness vector for the case of a p-wave, and the first break event in a marine seismic survey is a p-wave event. The rotation operator **R** should therefore be the identity matrix – that is, it should correspond to a rotation of 0° if the receiver heading is correct. If the rotation operator **R** corresponds to a non-zero angle of rotation, this indicates that the estimated polarisation is not parallel to the estimated slowness vector and this, in turn, suggests that the heading of the receiver is not correct. In this example, inspection of the rotation operator **R** suggests that the polarisation vector should be rotated approximately 2° in a clockwise direction to make it parallel to the slowness vector. This suggests that the axes of the horizontal geophones are oriented 2° anti-clockwise from their expected orientation (that is, the internal x-axis of the x-component geophone, which should be oriented to lie due north, is in fact oriented approximately 2° to the west of north). The receiver heading is therefore incorrect, by approximately 2°.

The gain operator **G** should, in the absence of vector infidelity, be the identity matrix. Examination of the diagonal terms of the gain operator **G** obtained in the above example suggests a gain imbalance of approximately 18% between x- and y- geophone components. That is, the gain operator **G** indicates that the recorded amplitude of the y-component of the received seismic energy should be increased by approximately 18% to compensate for vector infidelity.

The non-zero off-diagonal components of the operator **G** indicate a small amount of cross-coupling between the x- and y- components of the receiver.

It is now possible to correct the acquired seismic data for the effects of receiver mis-orientation and vector infidelity, by applying the transfer operator to the acquired seismic data. Figures 4(a), 4(b) and 5 show the effect of applying the transfer operator **M** to the seismic data.

Figures 4(a) and 4(b) show the difference between the azimuth of the slowness vector and the azimuth of the polarisation vector, plotted as a function of the source co-ordinates relative to the minimum travel time position. Figure 4(a) shows the results of plotting the raw received data, and Figure 4(b) shows results for data after correction using the transfer operator **M**. It will be seen that the magnitude of the difference between the azimuth of the slowness vector and the azimuth of the polarisation vector is significantly lower in Figure 4(b) than in Figure 4(a). The scale of –21 to 21 indicates the angle in degrees between the azimuth of the slowness vector and the azimuth of the polarisation vector.

Figure 5 shows the angle the slowness vector and the polarisation vector plotted as a function of the azimuth from the receiver to the source. It shows the angle that the polarisation vector makes with the vertical plane in which it should ideally be constrained. Data points for the raw received seismic data are shown by an "x", and data points for seismic data after correction using the transfer operator **M** are plotted using a "+".

It will be noted from Figures 4(a), 4(b) and 5 that the angle between the slowness vector and the polarisation vector has been significantly reduced by correcting the data using the transfer operator **M**.

In the embodiments described above, the slowness vector is obtained from the acquired seismic data, for example by differentiating the relationship between the travel time and the corrected offset. In an alternative embodiment of the invention, the slowness vector is used to compute a modelled polarisation. This may be done when relevant seismic properties of the target geological area are known. For example, in the case of an ocean bottom cable (OBC) seismic survey in which the receiver is disposed on the sea bed, it is possible to model the polarisation vector from the observed slowness vector if the properties of the sea bed (such as the p- and s- wave velocities of the sea bed, the density of the sea bed and the tilt of the sea-bed) are known. In this alternative embodiment, the transfer operator is determined by a linear inversion process on the

modelled polarisation vector and the observed polarisation vector as determined from the received seismic data.

The modelled polarisation vector, p_{mod}, is related to the observed polarisation of the seismic data, p_{obs}, in a similar way to the slowness vector and polarisation vector:

$$p_{mod} = \mathbf{M}\, p_{obs}$$

In equation (4), **M** is again a transfer operator. It is, however, now a 3x3 matrix rather than a 2x2 matrix.

Equation (4) can be re-arranged, so as to give the transfer operator **M**, and decomposed to give the rotation and gain operators **R**, **G** in a similar way as described above.

This method may also allow for the inversion of sea floor properties. To do this, observed polarisation vector and the observed slowness vector are each derived from the acquired seismic data, and are used as data which are inverted to yield local elastic properties for the medium surrounding the receiver.

In the embodiments described above, the method has been performed in the time domain so that the polarisation vector obtained from the acquired seismic data is frequency-independent. In this case, the transfer operator that is derived will also be frequency-independent. It would alternatively be possible to perform the method in the frequency domain, for example by band passing the received seismic data and re-computing the polarisation estimates, thereby allowing the construction of a frequency-dependent transfer operator.

The method may also be used to model non-linear polarisation vectors, by using a transfer operator whose elements include complex numbers.

Figure 6 is a schematic block diagram of an apparatus 1 according to the present invention. The apparatus is able to carry out a method according to the present invention.

The apparatus 1comprises a programmable data processor 2 with a program memory 3, for instance in the form of a read only memory ROM, storing a program for controlling the data processor 2 to perform a method of the invention. The system further comprises non-volatile read/write memory 4 for storing, for example, any data which must be retained in the absence of power supply. A "working" or "scratchpad" memory for the data processor is provided by a random access memory (RAM) 5. An input device 6 is provided, for instance for receiving user commands and data. An output device 7 is provided, for instance for displaying information relating to the progress and result of the method. The output device may be, for example, a printer, a visual display unit or an output memory.

Seismic data for processing according to a method of the invention may be supplied via the input device 6 or may optionally be provided by a machine-readable store 8.

The program for operating the system and for performing the method described hereinbefore is stored in the program memory 3, which may be embodied as a semi-conductor memory, for instance of the well-known ROM type. However, the program may be stored in any other suitable storage medium, such as magnetic data carrier 3a (such as a "floppy disc") or CD-ROM 3b.

CLAIMS:

1. A method of processing multi-component seismic data acquired at a receiver, the method comprising the steps of:

a) determining the components of the slowness vector of the acquired seismic data along first and second horizontal directions, the first and second directions not being co-linear;

b) determining the components of the polarisation vector of the acquired seismic data along the first and second horizontal directions; and

c) obtaining information about the orientation of the receiver and/or information about the vector infidelity of the receiver from the horizontal components of the slowness vector and the horizontal components of the polarisation vector.

2. A method as claimed in claim 1 wherein step (c) comprises determining a transfer operator from the horizontal components of the slowness vector and the horizontal components of the polarisation vector.

3. A method as claimed in claim 2 and comprising the further step of determining a rotation operator from the transfer operator.

4. A method as claimed in claim 2 or 3 and comprising the further step of determining a gain operator from the transfer operator.

5. A method as claimed in any preceding claim and comprising the step of determining the horizontal components of the slowness vector from the seismic data acquired at the receiver.

6. A method as claimed in claim 5 wherein the step of determining the slowness from the acquired seismic data comprises determining a receiver position at which the travel time of seismic energy from the source to the receiver is at a minimum.

7. A method as claimed in any preceding claim wherein the transfer operator is obtained from the equation $s = \mathbf{M}\, p$ where s is a normalised slowness vector, p is a normalised polarisation vector and $\mathbf{M}$ is the transfer operator.

8. A method of processing multi-component seismic data acquired at a seismic receiver, the method comprising the steps of:

a) calculating the expected polarisation vector of seismic data acquired at the receiver;

b) determining the observed polarisation vector of seismic data acquired at the receiver; and

c) obtaining information about the orientation of the receiver and/or information about the vector infidelity of the receiver from the expected polarisation vector and the observed polarisation vector.

9. A method as claimed in claim 8 wherein step (c) comprises determining a transfer operator from the expected polarisation vector and the observed polarisation vector.

10. A method as claimed in claim 9 wherein the step of calculating the expected polarisation vector comprises calculating the expected polarisation vector from the observed slowness vector.

11. A method as claimed in claim 9 or 10 wherein the transfer operator is calculated from

$$p_{\mathrm{mod}} = \mathbf{M}\, p_{\mathrm{obs}}$$

where p_{mod} is the expected polarisation vector, p_{obs} is the observed polarisation vector, and $\mathbf{M}$ is the transfer operator.

12. A method as claimed in any of claims 9 to 11 and comprising the further step of determining a rotation operator from the transfer operator.

13. A method as claimed in any of claims 9 to 12 and comprising the further step of determining a gain operator from the transfer operator.

14. A method as claimed in any of claims 2 to 8 and 10 to 13 wherein the transfer operator is a frequency-dependent transfer operator.

15. A method of processing multi-component seismic data acquired at a receiver, the method comprising the steps of:

determining a transfer operator according to a method as defined in any of claim 2 to 8 and 10 to 14; and

processing the acquired seismic data using the transfer operator thereby to correct the acquired seismic data for mis-orientation of the receiver and/or vector infidelity of the receiver.

16. A method of processing multi-component seismic data acquired at a receiver as claimed in claim 15, the method further comprising the step of applying one or more subsequent processing steps to the corrected seismic data.

17. A method of seismic surveying comprising the steps of

acquiring multi-component seismic data at a seismic receiver; and

processing the seismic data according to a method as defined in any one of claims 1 to 16.

18. A method as claimed in any preceding claim wherein the seismic data are common receiver gather seismic data.

19. An apparatus for processing multi-component seismic data acquired at a receiver, the apparatus comprising:

a) means for determining the components of the slowness vector of the acquired seismic data along first and second horizontal directions, the first and second directions not being co-linear;

b) means for determining the components of the polarisation vector of the acquired seismic data along the first and second horizontal directions; and

c) means obtaining information about the orientation of the receiver and/or information about the vector infidelity of the receiver from the horizontal components of the slowness vector and the horizontal components of the polarisation vector.

20. An apparatus in claim 19 and comprising means for determining a transfer operator from the horizontal components of the slowness vector and the horizontal components of the polarisation vector.

21. An apparatus for processing multi-component seismic data acquired at a seismic receiver, the method comprising the steps of:

a) means for calculating the expected polarisation vector of seismic data acquired at the receiver;

b) means for determining the observed polarisation vector of seismic data acquired at the receiver; and

c) means obtaining information about the orientation of the receiver and/or information about the vector infidelity of the receiver from the expected polarisation vector and the observed polarisation vector.

22. An apparatus as claimed in claim 21 and comprising means for determining a transfer operator from the expected polarisation vector and the observed polarisation vector.

23. An apparatus as claimed in any of claims 19 to 22 and comprising a programmable data processor.

24. A storage medium containing a program for a data processor of an apparatus as claimed in claim 23.

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